WHITING PETROLEUM CORP
Form 10-K
February 24, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2010

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission file number: 001-31899
WHITING PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-0098515 (I.R.S. Employer Identification No.)
1700 Broadway, Suite 2300 Denver, Colorado (Address of principal executive offices)	80290-2300 (Zip code)

(303) 837-1661
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

6.25% Convertible Perpetual Preferred Stock, $0.001 par value	New York Stock Exchange
Common Stock, $0.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange
(Title of Class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.YesT No £

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Act.Yes£ No T

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes T No £

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. T

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filerT Accelerated filer £ Non-accelerated filer£ Smaller reporting company £

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes£ No T

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2010: $4,012,157,212.

Number of shares of the registrant's common stock outstanding at February 22, 2011: 118,115,582 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2011 Annual Meeting of Stockholders are incorporated by reference into Part III.

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GLOSSARY OF CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms “we,” “us,” “our” or “ours” when used in this Annual Report on Form 10-K refer to Whiting Petroleum Corporation, together with its consolidated subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

“3-D seismic” Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

“Bbl” One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil and other liquid hydrocarbons.

“Bcf” One billion cubic feet of natural gas.

“Bcfe” One billion cubic feet of natural gas equivalent.

“BOE” One stock tank barrel equivalent of oil, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

“CO2 flood” A tertiary recovery method in which CO2 is injected into a reservoir to enhance hydrocarbon recovery.

“completion” The installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“deterministic method” The method of estimating reserves or resources using a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation.

“farmout” An assignment of an interest in a drilling location and related acreage conditioned upon the drilling of a well on that location.

“FASB” Financial Accounting Standards Board.

“FASB ASC” The Financial Accounting Standards Board Accounting Standards Codification.

“GAAP” Generally accepted accounting principles in the United States of America.

“MBbl” One thousand barrels of oil or other liquid hydrocarbons.

“MBOE” One thousand BOE.

“MBOE/d” One MBOE per day.

“Mcf” One thousand cubic feet of natural gas.

“Mcfe” One thousand cubic feet of natural gas equivalent.

“MMBbl” One million Bbl.

"MMBOE" One million BOE.

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“MMBtu” One million British Thermal Units.

“MMcf” One million cubic feet of natural gas.

“MMcf/d” One MMcf per day.

“MMcfe/d” One MMcfe per day.

“PDNP” Proved developed nonproducing reserves.

“PDP” Proved developed producing reserves.

“plugging and abandonment” Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

“possible reserves” Those reserves that are less certain to be recovered than probable reserves.

“pre-tax PV10%” The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the Securities and Exchange Commission (“SEC”), net of estimated lease operating expense, production taxes and future development costs, using price and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or Federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC. See footnote (1) to the Proved Reserves table in Item 1. “Business” of this Annual Report on Form 10-K for more information.

“probable reserves” Those reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

“proved developed reserves” Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

“proved reserves” Those reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

“proved undeveloped reserves” Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are schedule to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

“PUD” Proved undeveloped reserves.

“reasonable certainty” If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

“reserves” Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

“reservoir” A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“resource play” Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

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“working interest” The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. We were incorporated in 2003 in connection with our initial public offering.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through property acquisitions, development and exploration activities. As of December 31, 2010, our estimated proved reserves totaled 304.9 MMBOE, representing an 11% increase in our proved reserves since December 31, 2009. Our 2010 average daily production was 64.6 MBOE/d and implies an average reserve life of approximately 12.9 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2010, their corresponding pre-tax PV10% values, and our December 2010 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2010:

	Proved Reserves (1)						
Core Area	Oil (2) (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil (2)		Pre-Tax PV10% Value (3) (In millions)	4th Quarter 2010 Average Daily Production (MBOE/d)
Permian Basin	115.6	47.9	123.6	94	%	$ 1,471.5	12.2
Rocky Mountains	94.5	162.8	121.6	78	%	2,425.5	40.8
Mid-Continent	38.2	19.9	41.5	92	%	955.2	9.3
Gulf Coast	3.2	36.9	9.4	34	%	113.3	2.7
Michigan	2.8	36.0	8.8	32	%	78.9	2.9
Total	254.3	303.5	304.9	83	%	$ 5,044.4	67.9
Discounted Future Income Taxes	-	-	-	-		(1,376.8)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-		$ 3,667.6	-

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2010, pursuant to current SEC and FASB guidelines.

(2) Oil includes natural gas liquids.

(3) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors

may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our proved oil and natural gas reserves.

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While historically we have grown through acquisitions, we are increasingly focused on a balance between exploration and development programs and continuing to selectively pursue acquisitions that complement our existing core properties. We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities.

Our growth plan is centered on the following activities:

- pursuing the development of projects that we believe will generate attractive rates of return;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

During 2010, we incurred $1,007.6 million in exploration, development and total acquisition expenditures, including $822.9 million for the drilling of 189 gross (88.0 net) wells. Of these new wells, 84.3 (net) resulted in productive completions and 3.7 (net) were unsuccessful, yielding a 96% success rate.

Our current 2011 capital budget is $1,350.0 million, and included in this amount is approximately $110.0 million in acreage acquisition costs. Previously, we have not included acreage acquisition costs in our annual capital budgets. However, during 2010 we incurred $155.5 million in aggregate acreage purchases and have therefore decided to include such costs in our capital budgets going forward. The 2011 capital budget of $1,350.0 million represents a 38% increase from the $978.3 million in exploration, development and acreage expenditures we incurred in 2010. We expect to fund substantially all of our 2011 capital budget using net cash provided by operating activities, which has increased primarily in response to the higher oil prices experienced throughout 2010 and continuing into the first part of 2011, as well as in response to higher crude oil production volumes.

Acquisitions and Divestitures

The following is a summary of our acquisitions and divestitures during the last two years. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for more information on these acquisitions and divestitures.

2010 Acquisitions. In September 2010, we acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate unadjusted purchase price was $19.2 million, and substantially all of it was allocated to the properties and acreage acquired.

In August 2010, we acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for $26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

2010 Divestitures. We did not have any significant divestitures during the year ended December 31, 2010.

2009 Acquisitions. During 2009, we acquired additional royalty and overriding royalty interests in the North Ward Estes field and various other fields in the Permian Basin in two separate transactions with private owners. Also included in these transactions were contractual rights, including an option to participate for an aggregate 10% working interest and right to back in after payout for an additional aggregate 15% working interest in the development of deeper pay zones on acreage under and adjoining the North Ward Estes field.

We completed the first acquisition of additional royalty and overriding royalty interests in November 2009, with a purchase price of $38.7 million and an effective date of October 1, 2009. The average daily net production attributable to this transaction was approximately 0.3 MBOE/d in September 2009. Estimated proved reserves attributable to the acquired interests are 2.2 MMBOE, resulting in an acquisition price of $17.59 per BOE. We completed the second acquisition of additional royalty and overriding royalty interests in December 2009, with a purchase price of $27.4 million and an effective date of November 1, 2009. The average daily net production attributable to this transaction was approximately 0.2 MBOE/d in September 2009. Estimated proved reserves attributable to the acquired interests are 1.6 MMBOE, resulting in an acquisition price of $17.13 per BOE. Reserves attributable to royalty and overriding royalty interests are not burdened by operating expenses or any additional capital costs, including CO_2 costs, which are paid by the working interest owners.

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In aggregate, the two acquisitions in the North Ward Estes field represent 3.8 MMBOE of proved reserves at an acquisition price of $66.1 million, or $17.39 per BOE. These two acquisitions were funded primarily from net cash provided by operating activities. Substantially all of the purchase price was allocated to the properties acquired.

2009 Participation Agreement. In June 2009, we entered into a participation agreement with a privately held independent oil company covering twenty-five 1,280-acre units and one 640-acre unit located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, the private company agreed to pay 65% of our net drilling and well completion costs to receive 50% of our working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, we will remain the operator for each unit.

At the closing of the agreement, the private company paid us $107.3 million, representing $6.4 million for acreage costs, $65.8 million for 65% of our cost in 18 wells drilled or drilling and $35.1 million for a 50% interest in our Robinson Lake gas plant and oil and gas gathering system, resulting in a pre-tax gain on sale of $4.6 million. We used these proceeds to repay a portion of the debt outstanding under our credit agreement.

Business Strategy

Our goal is to generate meaningful growth in our net asset value per share of proved reserves by acquisition, exploitation and exploration of oil and gas projects with attractive rates of return on capital employed. To date, we have pursued this goal through both the acquisition of reserves and continued field development in our core areas. Because of our extensive property base, we are pursuing several economically attractive oil and gas opportunities to exploit and develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin and Denver Julesburg Basin (“DJ Basin”) projects has become one of our central objectives. As of December 31, 2010, we have assembled approximately 109,200 gross (66,500 net) acres on the eastern side of the Williston Basin in North Dakota in an active oil development play at our Sanish field area, where the Middle Bakken reservoir is oil productive. As of February 15, 2011, we have participated in the drilling of 229 successful wells (172 operated) in our Sanish field acreage that had a combined net production rate of 22.3 MBOE/d during December 2010.

As of December 31, 2010, we have assembled approximately 360,500 gross (234,900 net) acres in the Lewis & Clark Prospect in Billings, Golden Valley and Stark Counties, North Dakota. Through the end of 2010 we have drilled seven horizontal wells into the Three Forks reservoir at Lewis & Clark, and the average production from these seven wells was approximately 0.6 MBOE/d during the first 30 days of production. We hold a working interest in 250 1,280-acre spacing units in the Lewis & Clark Prospect, and we estimate two to four wells per 1,280-acre spacing unit to fully develop this area. We currently have five drilling rigs operating in this project, and we plan to double this rig count by the end of 2011.

In addition to the Lewis & Clark Prospect, we have assembled acreage positions in the Cassandra, Hidden Bench and Big Island prospects located in North Dakota, and the Starbuck Prospect, located in Montana. In aggregate we have assembled approximately 289,600 gross (206,100 net) acres. In 2011 we intend to test each area with one or more wells.

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In May 2008 we acquired interests in the Flat Rock Gas field in Uintah County, Utah. The main production in the Flat Rock field is from the Entrada formation. In late 2009 and early 2010, we entered into 5-year fixed-price gas contracts that averaged over $5.15 per Mcf at our Flat Rock field to maintain the economic viability of this production. During 2010, we drilled four wells in our Flat Rock field.

In September 2010, we acquired operated interests in 19 producing oil and gas wells, undeveloped acreage and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres at our Redtail Prospect in Weld County, Colorado, which brings our total acreage position in that area to approximately 89,400 gross (66,100 net) acres. Drilling in this area will target the Niobrara formation. We initiated a seven well exploratory drilling program in late 2010 that will continue through June 2011, and we have drilled four wells as of February 15, 2011. Based on our current acreage position and a successful exploratory program, we could operate up to 220 wells and participate in an additional 125 non-operated wells. Initial flow rates from the Niobrara formation in the DJ Basin recently announced by other operators are ranging from 600 to 1,600 Bbls of oil per day from multi-stage fracture stimulated horizontal wells. As of December 31, 2010, we have leased over 78,800 gross (66,200 net) acres in our Big Tex Prospect in the Delaware Basin of West Texas, where we will be targeting the Wolfcamp and Bone Springs formations. Production from these two areas will be primarily oil.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past five years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2010, we have identified a drilling inventory of over 2,200 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists of the development of our proved and non-proved reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several opportunities to apply and expand enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. In 2005, we acquired two large oil fields, the Postle field, located in the Oklahoma Panhandle, and the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced significant production increases to date in these fields through the use of secondary and tertiary recovery techniques, and we anticipate such production increases at the North Ward Estes field to continue over the next four to seven years. In these fields, we are actively injecting water and CO_2 and executing extensive re-development, drilling and completion operations, as well as enhanced gas handling and treating capability.

Growing Through Accretive Acquisitions. From 2004 to 2010, we completed 16 separate acquisitions of producing properties for estimated proved reserves of 230.9 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, land, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, negotiating and closing purchases and managing acquired properties. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings and internally generated cash flow, as appropriate, to maintain our strong financial position. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars and fixed price gas contracts to provide an attractive base commodity price level.

Competitive Strengths

We believe that our key competitive strengths lie in our balanced asset portfolio, our experienced management and technical team and our commitment to effective application of new technologies.

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Balanced, Long-Lived Asset Base. As of December 31, 2010, we had interests in 9,698 gross (3,755 net) productive wells across approximately 1,115,000 gross (560,800 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities in executing our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 12.9 years based on year-end 2010 proved reserves and 2010 production.

Experienced Management Team. Our management team averages 28 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 30 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 6,560 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. With the acquisition of the Postle and North Ward Estes properties, we have assembled a team of 13 professionals averaging over 22 years of expertise managing CO_2 floods. This provides us with the ability to pursue other CO_2 flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

In June 2009, we implemented a “Drill Well on Paper” (“DWOP”) process on our drilling program in the Sanish field in North Dakota. DWOP is an optimization program for all parties involved in the drilling process to engage in looking for ways to reduce the time and costs associated with the drilling of a well. The first step in the DWOP process is to determine the “technical limit” time, which is the time necessary to drill the perfect well. We then perform a step-by-step analysis of the drilling process with the ultimate goal of drilling a well within the technical limit time. The program has been very successful in the Sanish field where all of our operated rigs have been through the program. In 2009, we reduced drilling time by 10 days per well, from 38 days to 28 days. In 2010, we experienced continued success and were able to reduce the drilling time by an additional 8 days. We plan to expand this program to all of our operated rigs in North Dakota in 2011.

In 2010, we were the first to implement a 24-stage fracture stimulation treatment utilizing sliding sleeve technology and have recently run the equipment to pump a 30-stage sliding sleeve stimulation. On March 1, 2010, we completed the installation of 298 permanent geophones across the Sanish field which has allowed us to gather microseismic data on every fracture stimulation we have pumped in the field. This information has been useful in determining the effectiveness of our hydraulic stimulations along with assisting in developing the proper spacing of wellbores in the field.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2010 are summarized in the table below. See “Reserves” in Item 2 of this Annual Report on Form 10-K for information relating to the uncertainties surrounding these reserve categories.

Permian Basin:	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved		Estimated Future Capital Expenditures (In millions)
PDP	42.0	28.4	46.7	38	%	
PDNP	28.6	5.9	29.6	24	%	
PUD	45.0	13.6	47.3	38	%	
Total Proved	115.6	47.9	123.6	100	%	$814.5
Total Probable	39.9	53.3	48.7			$724.3
Total Possible	109.8	13.9	112.2			$836.2
Rocky Mountains:						
PDP	68.8	110.0	87.1	72	%	
PDNP	0.4	2.3	0.8	1	%	
PUD	25.3	50.5	33.7	27	%	
Total Proved	94.5	162.8	121.6	100	%	$492.5
Total Probable	14.2	129.8	35.8			$480.8
Total Possible	68.9	152.9	94.4			$1,079.6
Mid-Continent:						
PDP	33.5	19.0	36.6	88	%	
PDNP	0.6	0.6	0.7	2	%	
PUD	4.1	0.3	4.2	10	%	
Total Proved	38.2	19.9	41.5	100	%	$113.6
Total Probable	7.0	2.4	7.4			$209.4
Total Possible	-	-	-			$-
Gulf Coast:						
PDP	2.2	19.4	5.5	59	%	
PDNP	0.1	3.1	0.6	6	%	
PUD	0.9	14.4	3.3	35	%	
Total Proved	3.2	36.9	9.4	100	%	$49.6
Total Probable	1.8	21.9	5.5			$59.5
Total Possible	3.6	28.5	8.3			$94.3
Michigan:						
PDP	1.3	27.4	6.0	68	%	
PDNP	0.9	4.4	1.6	18	%	
PUD	0.6	4.2	1.2	14	%	
Total Proved	2.8	36.0	8.8	100	%	$21.7
Total Probable	1.8	4.8	2.7			$26.3
Total Possible	0.7	9.5	2.2			$25.6

Total Company:						
PDP	147.8	204.2	181.9	60	%	
PDNP	30.6	16.3	33.3	11	%	
PUD	75.9	83.0	89.7	29	%	
Total Proved	254.3	303.5	304.9	100	%	$1,491.9
Total Probable	64.7	212.2	100.1			$1,500.3
Total Possible	183.0	204.8	217.1			$2,035.7

The estimated future capital expenditures in the table above incorporate numerous assumptions and are subject to many uncertainties, including oil and natural gas prices, costs of oil field goods and services, drilling results and several other factors.

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Marketing and Major Customers

We principally sell our oil and gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. During 2010, sales to Shell Western E&P, Inc., Plains Marketing LP and Nexen Pipeline USA, Inc. accounted for 17%, 16% and 13%, respectively, of our total oil and natural gas sales. During 2009, sales to Shell Western E&P, Inc., Plains Marketing LP and EOG Resources, Inc. accounted for 18%, 15% and 13%, respectively, of our total oil and natural gas sales. During 2008, sales to Plains Marketing LP and Valero Energy Corporation accounted for 15% and 14%, respectively, of our total oil and natural gas sales. We believe that the loss of any individual purchaser would not have a long-term material adverse impact on our financial position or results of operations.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit agreement is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interfere with the use of our properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry.

Regulation

Regulation of Transportation, Sale and Gathering of Natural Gas

The Federal Energy Regulatory Commission (the "FERC") regulates the transportation, and to a lesser extent sale for resale, of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

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Our natural gas sales are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation and underground storage are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the FERC that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry that remain subject to the FERC's jurisdiction, most notably interstate natural gas transmission companies and certain underground storage facilities. These initiatives may also affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis.

The FERC implemented The Outer Continental Shelf Lands Act pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access and non-discriminatory transportation service. One of the FERC’s principal goals in carrying out this Act’s mandate is to increase transparency in the market to provide producers and shippers on the outer continental shelf with greater assurance of open access services on pipelines located on the outer continental shelf and non-discriminatory rates and conditions of service on such pipelines.

We cannot accurately predict whether the FERC’s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. In addition, many aspects of these regulatory developments have not become final, but are still pending judicial and final FERC decisions. Regulations implemented by the FERC in recent years could result in an increase in the cost of transportation service on certain petroleum product pipelines. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any of the states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Pipeline safety is regulated at both state and federal levels. We use the latest tools and technologies to remain compliant with current pipeline safety regulations.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for crude oil transportation rates that allowed for an increase or decrease in the cost of transporting oil to the purchaser. FERC’s regulations include a methodology for oil pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five-year review has revised the methodology for this index to now be based on Producer Price Index for Finished Goods (the "PPI-FG"), plus a 1.3% adjustment, for the period July 1, 2006 through July 2011. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

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Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and periodic report submittals during operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum allowable rates of production from oil and gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production or sale of oil, gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by Minerals Management Service ("MMS"). Currently, only 0.2% of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was $30.7 million as of December 31, 2010. Whiting is therefore required to comply with the regulations and orders issued by MMS under the Outer Continental Shelf Lands Act. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and approval for our lease development and production plans. MMS regulations also establish construction requirements for production facilities located on our federal offshore leases and govern the plugging and abandonment of wells and the removal of production facilities from these leases. Under limited circumstances, MMS could require us to suspend or terminate our operations on a federal lease.

MMS also establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Our oil and gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA") issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or facility construction commences, restrict the types, quantities and concentrations of various materials that can be released into the environment in connection with drilling and production activities, limit or prohibit project siting, construction, or drilling activities on certain lands located within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for unauthorized pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability.

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Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

The environmental laws and regulations which have the most significant impact on the oil and gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA" or "Superfund") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site or sites where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may fall within CERCLA's definition of a "hazardous substance". Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these materials have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other materials may have been disposed or released on, under, or from the properties owned or leased by us or on, under, or from other locations where these hydrocarbons and materials have been taken for disposal. In addition, many of these owned and leased properties have been operated by third parties whose management and disposal of hydrocarbons and materials were not under our control. Similarly, the disposal facilities where discarded materials are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired the property or business, and if the problem itself is not discovered until years later. Our properties, adjacent affected properties, the offsite disposal facilities, and the material itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed materials, including materials disposed or released by prior owners or operators or other third parties;
- to clean up contaminated property, including contaminated groundwater; or
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators.

At this time, we do not believe that we are a potentially responsible party with respect to any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

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Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350.0 million, while the liability limit for offshore facilities is the payment of all removal costs plus up to $75.0 million in other damages, but these limits may not apply if a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or if a party fails to report a spill or to cooperate fully in a cleanup. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of financial responsibility required under OPA may be increased up to $150.0 million, depending on the risk represented by the quantity or quality of oil that is handled by the facility. Any failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to administrative, civil or criminal enforcement actions. We believe we are in compliance with all applicable OPA financial responsibility obligations. Moreover, we are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act ("RCRA") is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a "generator" or "transporter" of hazardous waste or on an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy". Therefore, a substantial portion of RCRA's requirements do not apply to our operations because we generate minimal quantities of these hazardous wastes. However, these exploration and production wastes may be regulated by state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes as they are presently classified to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Water Act. The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit.

The EPA had regulations under the authority of the CWA that required certain oil and gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the Energy Policy Act of 2005 nullified most of the EPA regulations that required storm water permitting of oil and gas construction projects. There are still some state and federal rules that regulate the discharge of storm water from some oil and gas construction projects. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. In Section 40 CFR 112 of the regulations, the EPA promulgated the Spill Prevention, Control, and Countermeasure ("SPCC") regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards. The SPCC regulations were revised in 2002 and required the amendment of SPCC plans and the modification of spill control devices at many facilities. Since 2002 there have been numerous amendments and extensions for compliance with the 2002 rule and subsequent amendments. On October 7, 2010 the EPA extended the compliance date to November 10, 2011 for all facilities except drilling, production or workover facilities that are offshore, or have an offshore component, and for onshore facilities required to have and submit a facility response plan.

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Clean Air Act. The Clean Air Act restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases have been developed by the EPA and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all applicable air emissions regulations.

Global Warming and Climate Control. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs"), including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. On April 2, 2007, in Massachusetts, et al. v. EPA, the U.S. Supreme Court required the EPA to reconsider whether GHGs cause or contribute to the endangerment of public health and the environment. As a result, on December 7, 2009, the EPA made Endangerment and Cause or Contribute findings for GHGs under its authority delegated by the Clean Air Act. Based upon these findings, the EPA has begun to regulate GHG emissions from mobile sources (e.g., cars and trucks). In addition, the EPA has promulgated regulations concerning the inventory of and regulation of GHGs from stationary sources which include many of our facilities. Further, many states have taken legal measures to reduce emission of these gases, primarily through the planned development of GHG emission inventories, permitting programs and/or regional GHG cap and trade programs. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The Outer Continental Shelf Lands Act, for instance, requires the U.S. Department of Interior to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, the National Environmental Policy Act requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. The Coastal Zone Management Act, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and gas development. In obtaining various approvals from the Department of Interior, we must certify that we will conduct our activities in a manner consistent with all applicable regulations.

Employees

As of December 31, 2010, we had 561 full-time employees, including 28 senior level geoscientists and 52 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

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Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, exhibits and amendments to these reports, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission.

Item 1A. Risk Factors

Each of the risks described below should be carefully considered, together with all of the other information contained in this Annual Report on Form 10-K, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment.

Oil and natural gas prices are very volatile. An extended period of low oil and natural gas prices may adversely affect our business, financial condition, results of operations or cash flows.

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and gas exploration and production activity;
- the level of global oil and gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and gas in captive market areas; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. A substantial or extended decline in oil or natural gas prices may result in impairments of our proved oil and gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, we will be required to reduce spending or borrow any such shortfall. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

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Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success will depend on the success of our development, exploitation, production and exploration activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "— Reserve estimates depend on many assumptions that may turn out to be inaccurate..." later in these Risk Factors for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining qualified personnel or equipment, including drilling rigs and CO_2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

The development of the proved undeveloped reserves in the North Ward Estes field may take longer and may require higher levels of capital expenditures than we currently anticipate.

As of December 31, 2010, undeveloped reserves comprised 36% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $561.4 million at the North Ward Estes field as of December 31, 2010. This field encompasses 44% of our total estimated future development costs of $1,263.7 million related to proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO_2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Under our CO_2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO_2 to us and other parties with whom it has CO_2 contracts, then the supplier may reduce the amount of CO_2 on a pro rata basis it provides to us and such other parties. If this occurs or if we are otherwise limited in the quantities of CO_2 available to us, we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate, and our future oil and gas production volumes could be negatively impacted. These contracts are also structured as "take-or-pay" arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO_2 as part of our enhanced recovery techniques.

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Prospects that we decide to drill may not yield oil or gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this Annual Report on Form 10-K. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flow rates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, from more fully explored prospects, or from producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and gas properties.

Accounting rules require that we periodically review the carrying value of our producing oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, which may include depressed oil and natural gas prices, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and gas properties. For example, we recorded a $9.4 million impairment write-down during 2009 for the partial impairment of producing properties, primarily natural gas, in the Rocky Mountains region. A write-down constitutes a non-cash charge to earnings. We may incur additional impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves referred to in this Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves, as referred to in this report, is the current market value of our estimated proved oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and current costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2010 would have decreased from $3,667.6 million to $3,664.5 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2010 would have decreased from $3,667.6 million to $3,600.5 million.

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Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2010, we had $200.0 million in borrowings and $0.4 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with $899.6 million of available borrowing capacity, as well as $600.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement.

Our level of indebtedness and the covenants contained in the agreements governing our debt could have important consequences for our operations, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation's credit agreement may be at variable rates; and
- potentially limiting our ability to pay dividends in cash on our convertible perpetual preferred stock.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. In addition, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas Corporation's credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our debt under the credit agreement.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We may not be able to generate sufficient cash flow to pay the interest on our debt or future borrowings, and equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas Corporation's credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

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The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement contain various restrictive covenants that may limit our management's discretion in certain respects. In particular, these agreements will limit our and our subsidiaries' ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation's credit agreement requires us, as of the last day of any quarter, (i) to not exceed a total debt to the last four quarters' EBITDAX ratio (as defined in the credit agreement) of 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter and (ii) to have a consolidated current assets to consolidated current liabilities ratio (as defined in the credit agreement and which includes an add back of the available borrowing capacity under the credit agreement) of not less than 1.0 to 1.0. Also, the indentures under which we issued our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of these covenants, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation's credit agreement. A substantial or extended decline in oil or natural gas prices may adversely affect our ability to comply with these covenants.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas Corporation's credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures through a combination of equity and debt issuances, bank borrowings and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations and existing financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

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- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- the costs of producing oil and natural gas; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves.

The global recession and tight financial markets may have impacts on our business and financial condition that we currently cannot predict.

The current global recession and tight credit financial markets may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

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Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis or within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploration and development operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2010, we had identified a drilling inventory of over 2,200 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs of oil field goods and services, drilling results, ability to extend drilling acreage leases beyond expiration, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For example, during the fourth quarter of 2010, we recorded a $5.8 million non-cash charge for the impairment of unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken. Additionally, our rights to develop a portion of our undeveloped acreage may expire if not successfully developed or renewed. See “Acreage” in Item 2 of this Annual Report on Form 10-K for more information relating to the expiration of our rights to develop undeveloped acreage.

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Properties that we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program. From 2004 through 2010, we completed 16 separate acquisitions of producing properties with a combined purchase price of $1,900.3 million for estimated proved reserves as of the effective dates of the acquisitions of 230.9 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- timing of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, facility or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions to date have consisted of financially settled crude oil and natural gas forward sales contracts, primarily costless collars, placed with major financial institutions. As of January 1, 2011, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale for 2011 of between 904,255 and 904,917 barrels of oil per month and between 34,554 and 38,139 MMBtu of natural gas per month. All our oil hedges will expire by November 2013 and all our natural gas hedges will expire by December 2012. See “Quantitative and Qualitative Disclosure about Market Risk” in Item 7A of this Annual Report on Form 10-K for pricing and a more detailed discussion of our hedging transactions.

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas, or alternatively, we may decide to unwind or restructure the hedging arrangements we previously entered into. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we may otherwise receive from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions or unwind hedging transaction we previously entered into, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As such, subsequent to March 31, 2009 we recognize all gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. Subsequently, we may experience significant net income and operating result losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. For example, our net production from the Sanish field averaged 22,270 BOE/d in December 2010, a 3% decrease from 22,935 BOE/d in September 2010, due to well completion delays caused by inclement weather in North Dakota. Conditions such as these can therefore limit our ability to operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

The differential between the NYMEX or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

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Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. Thus, some of our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

Market conditions or operational impediments may hinder our access to oil and gas markets or delay our production.

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

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Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences; restrict the types, quantities, and concentration of materials that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Private parties, including the surface owners of properties upon which we drill, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance. Moreover, federal law and some state laws allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

Changes in environmental laws and regulations occur frequently and may serve to have a materially adverse impact on our business. For example, as a result of the explosion and fire on the Deepwater Horizon drilling rig in April 2010 and the release of oil from the Macondo well in the Gulf of Mexico, there has been a variety of governmental regulatory initiatives to make more stringent or otherwise restrict oil and natural gas drilling operations in certain locations. Any increased governmental regulation or suspension of oil and natural gas exploration or production activities that arises out of these incidents could result in higher operating costs, which could, in turn, adversely affect our operating results. Also, for instance, any changes in laws or regulations that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and gas industry in general.

Climate change legislation or regulations restricting emissions of “greenhouse gasses” could result in increased operating costs and reduced demand for oil and gas that we produce.

On December 15, 2009, the U.S. Environmental Protection Agency (the “EPA”) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (“GHGs”) present an endangerment to public heath and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions according to "best available control technology" standards for GHGs that were published by the EPA in its PSD and Title V Permitting Guidance for Greenhouse Gases document in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

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In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and many states have already taken legal measures to reduce emissions of GHGs, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA is issuing new regulations that limit emissions of GHGs associated with our operations which will require us to incur costs to inventory and reduce emissions of GHGs associated with our operations and could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Congress is considering legislation that would amend the federal Safe Drinking Water Act by repealing an exemption for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The legislation also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

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The loss of senior management or technical personnel could adversely affect us.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, Chairman and Chief Executive Officer; James T. Brown, President and Chief Operating Officer; Mark R. Williams, Senior Vice President, Exploration and Development; J. Douglas Lang, Vice President, Reservoir Engineering/Acquisitions; Rick A. Ross, Vice President, Operations; David M. Seery, Vice President, Land; Michael J. Stevens, Vice President and Chief Financial Officer; or Peter W. Hagist, Vice President, Permian Operations, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for available capital for investment in the oil and gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

In February 2010, President Obama's Administration released its proposed federal budget for fiscal year 2011 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

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In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations forthcoming in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "CFTC") and the SEC for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2010, the Permian Basin region contributed 123.6 MMBOE (94% oil) of estimated proved reserves to our portfolio of operations, which represented 41% of our total estimated proved reserves and contributed 12.3 MBOE/d of average daily production in December 2010.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interests in approximately 58,000 gross and net acres in Ward and Winkler Counties, Texas. The Yates Formation at 2,600 feet is the primary producing zone with additional production from other zones including the Queen at 3,000 feet. In the North Ward Estes field, the estimated proved reserves as of December 31, 2010 were 36% PDP, 28% PDNP and 36% PUD.

The North Ward Estes field is responding positively to our water and CO2 floods, which we initiated in May 2007. As of December 31, 2010, we were injecting over 240 MMcf/d of CO2 in this field. Production from the field has increased 9% from 7.0 MBOE/d in the fourth quarter of 2009 to 7.6 MBOE/d in the fourth quarter of 2010. In this field, we are developing new and reactivated wells for water and CO2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in eight phases. The first two phases were largely completed by March 2009, and Phase III began in December 2010. We plan to have all eight phases implemented by 2016.

In order to fully develop the proved undeveloped reserves at North Ward Estes within our currently planned timeframe, we will need to utilize significant quantities of purchased CO2. As of December 31, 2010, we currently have under contract 52% of the future CO2 volumes that we believe necessary to develop the North Ward Estes proved undeveloped reserves, and we are in negotiations with suppliers to enter into long-term contracts that would secure the remaining quantities of CO2 needed to develop the proved reserves at this field. We are therefore reasonably certain that we will be able to successfully obtain all the necessary CO2 quantities required to develop the North Ward Estes proved reserves within our planned timeframe. However, we cannot provide absolute assurance with respect to the timing or actual quantities of CO2 that will be obtainable for the development of oil and gas reserves at North Ward Estes.

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Big Tex Prospect. As of December 31, 2010, Whiting had accumulated approximately 78,800 gross (66,200 net) acres in our Big Tex prospect area in Pecos, Reeves and Ward Counties, Texas in the Delaware Basin. Prospective formations include the Wolfcamp and Bone Spring horizons. We have drilled and completed five vertical wells in the Big Tex prospect, and we plan to begin a four-well horizontal drilling program in the second quarter of 2011. We consider this play to be in an early stage, and further drilling is subject to evaluation of our drilling and completion results.

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming and California. As of December 31, 2010, our estimated proved reserves in the Rocky Mountain region were 121.6 MMBOE (78% oil), which represented 40% of our total estimated proved reserves and contributed 39.5 MBOE/d of average daily production in December 2010.

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses approximately 109,200 gross (66,500 net) acres. Net production in the Sanish field averaged 23.5 MBOE/d in the fourth quarter of 2010, a 96% increase from 12.0 MBOE/d in the fourth quarter of 2009. Including non-operated wells, there were 197 producing wells in the Sanish field at year-end 2010, and as of February 15, 2011, 24 wells were in the process of completion and 11 wells were being drilled. Of the 197 wells, 72 were completed in 2010. In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake Gas Plant. We expanded the plant during 2010, and in December 2010 we added additional equipment which brought the plant's inlet capacity to 60 MMcf/d. We intend to further expand the plant in order to increase our processing capability to 90 MMcf/d in the third quarter of 2011. We completed the installation of the 17-mile oil line connecting the Sanish field to the Enbridge pipeline in Stanley, North Dakota in late December 2009. As of December 31, 2010, the pipeline was moving approximately 27,200 Bbls of oil per day. This 8-inch diameter line has a daily capacity of approximately 65,000 barrels of oil per day. We expect to have substantially all of our operated production flowing through the pipeline into the Enbridge facility by the second quarter of 2011.

Parshall Field. Immediately east of the Sanish field is the Parshall field, where we own interests in approximately 73,100 gross (18,200 net) acres. Our net production from the Parshall field averaged 4.6 MBOE/d in the fourth quarter of 2010, a 32% decrease from 6.7 MBOE/d in the fourth quarter of 2009. As of February 15, 2011, we have participated in 127 Bakken wells in the Parshall field, the majority of which are operated by EOG Resources, Inc., all of which are producing. Of these wells, one operated well was completed in 2010.

Lewis & Clark Prospect. As of December 31, 2010, we have assembled approximately 360,500 gross (234,900 net) acres in our Lewis & Clark prospect along the Bakken Shale pinch-out in the southern Williston Basin. During 2010 we assembled acreage located primarily in Stark County, North Dakota. In this area, the Upper Bakken shale is thermally mature, moderately over-pressured, and we believe that it has charged reservoir zones within the immediately underlying Three Forks formation. We hold a working interest in 250 1,280-acre spacing units, and we estimate two to four wells per unit to fully develop this area. As of December 31, 2010, we had drilled seven horizontal wells into the Three Forks reservoir at Lewis & Clark, and the average production from these seven wells was approximately 0.6 MBOE/d during the first 30 days of production. We currently have five drilling rigs operating in this area, and we plan to double this rig count by the end of 2011. In January 2011, we also added a full-time dedicated fracture stimulation crew that will focus on the Lewis & Clark area. In addition, we recently broke ground on the construction of a gas processing plant at Lewis & Clark, which is expected to be completed in November 2011.

Flat Rock Field. We acquired the Flat Rock Field in May 2008 and took over operations June 1, 2008. In the Flat Rock field area in Uintah County, Utah, we have an acreage position consisting of approximately 22,000 gross (11,500 net) acres. During 2010, we drilled four successful wells in the field.

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Redtail Niobrara Prospect. As of December 31, 2010, we had approximately 89,400 gross (66,100 net) acres in our Redtail Niobrara prospect in the Weld County, Colorado portion of the DJ Basin. In late 2010, we initiated a seven well exploratory drilling program in the Niobrara that will continue through June of 2011 and will consist of two vertical pilot wells and five horizontal production wells. Based on our current acreage position and a successful exploratory program, we could operate up to 220 wells and participate in an additional 131 non-operated wells assuming 320-acre spacing. We have drilled four Niobrara wells as of February 15, 2011. However, this play is in an early stage, and further drilling is subject to evaluation of our drilling and completion results.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2010, the Mid-Continent region contributed 41.5 MMBOE (92% oil) of proved reserves to our portfolio of operations, which represented 14% of our total estimated proved reserves and contributed 9.2 MBOE/d of average daily production in December 2010. The majority of the proved value within our Mid-Continent operations is related to properties in the Postle field.

Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 25,600 gross (24,200 net) acres. Four of the units are currently active CO2 enhanced recovery projects. Our expansion of the CO2 flood at the Postle field continues to generate positive results. As of December 31, 2010, we were injecting 140 MMcf/d of CO2 in this field. Production from the field maintained an average net rate of 8.9 MBOE/d in the fourth quarter of 2010 and 2009. We manage our CO2 flood at Postle on a pattern-by-pattern basis in order to optimize utilization of CO2, production and ultimate recovery. A pattern typically consists of a producing well surrounded by four water/CO2 injectors. As a pattern matures, increasing volumes of water are alternated with CO2 injection to control gas breakthrough and sweep efficiency. This process, referred to as “WAG” (Water Alternating Gas), typically results in the highest possible oil recovery. However, the production response can be diminished during periods of high water injection. A number of patterns were cycled to water injection during the third and fourth quarters of 2010, which caused a normal slowing of oil response. Operations are underway to expand CO2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO2 floods. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells. In the Postle field, the estimated proved reserves as of December 31, 2010 were 93% PDP, 2% PDNP and 5% PUD.

We are the sole owner of the Dry Trails Gas Plant located in the Postle field. This gas processing plant utilizes a membrane technology to separate CO2 gas from the produced wellhead mixture of hydrocarbon and CO2 gas so that the CO2 gas can be re-injected into the producing formation.

In addition to the producing assets and processing plant, we have a 60% interest in the 120-mile Transpetco operated CO2 transportation pipeline, thereby assuring the delivery of CO2 to the Postle field at a fair tariff. We have a long-term CO2 purchase agreement to provide the necessary CO2 for the expansion planned in the field.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2010, the Gulf Coast region contributed 9.4 MMBOE (34% oil) of proved reserves to our portfolio of operations, which represented 3% of our total estimated proved reserves and contributed 2.7 MBOE/d of average daily production in December 2010.

Eagle Ford Trend. We own acreage in the Nordheim, Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers fields along the Eagle Ford Trend in Karnes, Dewitt, Live Oak and Lavaca Counties, Texas. In 2007, we farmed out the Kawitt and Nordheim lease position to another operator who is developing the Eagle Ford Trend with horizontal wellbores. Under the terms of this agreement, we were carried on all drilling and completion costs on four Eagle Ford Trend wells, and Whiting maintained a 16.67% working interest in the completed wells. Going forward, we had the option to participate upfront for a 25% working interest in additional wells to be drilled or elect to take the 25% working interest after payout has occurred. To date, we have elected to take a 25% after payout working interest in seven wells drilled under this farmout. The operator has been successful in drilling Eagle Ford wells and by December 31, 2010 had drilled and completed ten wells. Our net production from the area was 5.3 MMcf/d in December 2010.

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Michigan Region

As of December 31, 2010, our estimated proved reserves in the Michigan region were 8.8 MMBOE (32% oil), and our December 2010 daily production averaged 2.8 MBOE/d. Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells located in the northern part of the state. The remainder of the Michigan reserves are typified by more conventional oil and gas production located in the central and southern parts of the state. We also operate the West Branch and Reno gas processing plants. The West Branch Plant gathers production from the Clayton unit, West Branch field and other smaller fields.

Marion 3-D Project. The Marion Prospect, located in Missaukee, Clare and Osceola Counties, Michigan, covers approximately 16,000 gross (14,700 net) acres. Analysis of seismic data identified two drillable prospects, and in late 2010, we drilled one of these prospects and are in the process of completing the well. The second prospect will be drilled in early 2011.

Reserves

As of December 31, 2010, all of our oil and gas reserves are attributable to properties within the United States. A summary of our oil and gas reserves as of December 31, 2010 based on average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2010) is as follows:

Summary of Oil and Gas Reserves as of Fiscal-Year End Based on Average Fiscal-Year Prices

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves			
Developed	178,409	220,530	215,164
Undeveloped	75,869	83,014	89,705
Total proved—December 31, 2010	254,278	303,544	304,869
Probable reserves			
Developed	1,850	10,864	3,661
Undeveloped	62,856	201,337	96,412
Total probable—December 31, 2010	64,706	212,201	100,073
Possible reserves			
Developed	16,149	8,407	17,550
Undeveloped	166,866	196,358	199,592
Total possible—December 31, 2010	183,015	204,765	217,142

Proved reserves. Estimates of proved developed and undeveloped reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

In 2010, total extensions and discoveries of 33.3 MMBOE were primarily attributable to successful drilling in the Sanish field and related proved undeveloped well locations added during the year, which in turn extended the proved acreage in that area.

In 2010, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 19.7 MMBOE. Included in these revisions were (i) 15.4 MMBOE of upward adjustments caused by higher crude oil and natural gas prices incorporated into our reserve estimates at December 31, 2010 as compared to December 31, 2009 and (ii) 4.3 MMBOE of net upward adjustments attributable to reservoir analysis and well performance. The liquids component of the net 4.3 MMBOE revision consisted of a 7.4 MMBOE increase that was primarily related to the Sanish field, where reserve assignments for proved developed producing as well as proved undeveloped well locations were adjusted upward to reflect the current performance of producing wells. The gas component of the net 4.3 MMBOE revision consisted of a 3.1 MMBOE decrease that was primarily related to the Beall East field where three proved undeveloped locations were removed from our proved reserve estimates since those wells are no longer planned to be drilled due to continued low gas prices.

Proved undeveloped reserves. From December 31, 2009 to December 31, 2010, our proved undeveloped reserves ("PUDs") decreased 11% or 10.7 MMBOE. This decrease in proved undeveloped reserves was primarily attributable to PUDs being converted to proved developed at the Sanish and North Ward Estes fields, and such decrease was partially offset by PUD locations added at the Sanish field. The Sanish PUD conversion was the result of our active drilling program in that field during 2010. The PUD conversion at North Ward Estes was due to the continuing expansion of our CO2 enhanced recovery project in that field. There were 25.8 MMBOE of PUDs that were converted into proved developed reserves due to 71 proved undeveloped well locations that were drilled and placed on production during 2010. We incurred $208.7 million in capital expenditures, or $8.09 per BOE, to drill and bring on-line these 71 PUD locations. In addition, there were approximately 18.2 MMBOE of PUDs that became proved developed reserves in 2010 at our CO2 enhanced recovery projects in the Postle and North Ward Estes fields. These PUDs were converted to proved developed at a cost of approximately $15.11 per BOE. Combining the PUD drilling conversions with the PUD enhanced oil recovery conversions, the Company converted 44.0 MMBOE of PUDs to proved developed reserves during 2010 at a cost of $10.99 per BOE.

Based on our 2010 year end independent engineering reserve report, we will drill all of our individual PUD drilling locations within five years. However, we do have certain quantities of proved undeveloped reserves in the North Ward Estes field that will remain in the PUD category for periods extending beyond five years because of certain external factors that preclude the development of the North Ward Estes enhanced oil recovery PUDs all at once. Due to the large areal extent of the field, the CO2 enhanced recovery project will progress through the field in a sequential manner as earlier injection areas are completed and new injection areas are initiated. External factors that preclude the initiation of the CO2 project throughout the field at the same time include (i) the volume of injection water necessary to repressure the reservoir in advance of the CO2 injection, (ii) the volume of purchased and recycled CO2 necessary to be injected to process the oil in the reservoir and (iii) the equipment and manpower necessary to build the infrastructure and prepare the wells for the CO2 enhanced recovery project. Our staged development plan is designed to expand the project as quickly and efficiently as possible to fully develop the field.

Probable reserves. Estimates of probable developed and undeveloped reserves are inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate that is as likely as not to be achieved. Estimates of probable reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate probable reserve quantities, and when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Increases in probable reserves during 2010 were primarily attributable to (i) 32 new probable undeveloped well locations, which were added in 2010 as a result of our drilling activity on newly acquired acreage in North Dakota, and (ii) new probable undeveloped reserves assigned to the expansion of our CO2 enhanced recovery project in the Postle field.

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Possible reserves. Estimates of possible developed and undeveloped reserves are also inherently imprecise. When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

We use deterministic methods to estimate possible reserve quantities, and when deterministic methods are used to estimate possible reserve quantities, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and we believe that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Possible reserves increased during 2010 primarily due to the acquisition of new producing properties south of our North Ward Estes field in 2010. We plan on carrying out waterflood and CO2 enhanced recovery projects on these newly acquired fields, and such projects have possible reserves associated with them.

At December 31, 2010, our probable reserves were estimated to be 100.1 MMBOE and our possible reserves were estimated to be 217.1 MMBOE, for a total of 317.2 MMBOE. The enhanced oil recovery ("EOR") project at our North Ward Estes field represented 130.2 MMBOE, or 41%, of our total 317.2 MMBOE probable and possible reserve quantities. In order to fully develop the EOR probable and possible reserves at North Ward Estes, we will need to utilize significant quantities of purchased CO2. We are currently in negotiations and planning for future sources capable of generating sufficient CO2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO2 supplies is subject to uncertainty and may require significant future capital expenditures by us, and we cannot therefore provide assurance with respect to the timing or actual quantities of CO2 that will be obtainable for the development such reserves.

Preparation of reserves estimates. The Company maintains adequate and effective internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is updated annually, is assessed for validity when the reservoir engineers hold technical meetings with geoscientists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from the Company's accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. The Company's current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated in the reserve database as well and verified to ensure their accuracy and completeness. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, Whiting's independent engineering firm Cawley, Gillespie & Associates, Inc. ("CG&A") meets with Whiting's technical personnel in the Company's Denver and Midland offices to review field performance and future development plans. Following these reviews the reserve database and supporting data is furnished to CG&A so that they can prepare their independent reserve estimates and final report. Access to the Company's reserve database is restricted to specific members of the reservoir engineering department.

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CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Robert Ravnaas, Executive Vice President. Mr. Ravnaas is a State of Texas Licensed Professional Engineer. See Exhibit 99.2 of this Annual Report on Form 10-K for the Report of Cawley, Gillespie & Associates, Inc. and further information regarding the professional qualifications of Mr. Ravnaas.

Our Vice President of Reservoir Engineering and Acquisitions is responsible for overseeing the preparation of the reserves estimates. He has over 37 years of experience, the majority of which has involved reservoir engineering and reserve estimation, holds a Bachelor's Degree in Petroleum Engineering from the University of Wyoming, holds an MBA from the University of Denver and is a registered Professional Engineer. He has also served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2010. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross(2)	Net(2)	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	44,868	23,635	120,387	78,643	165,255	102,278
Louisiana	40,064	7,479	3,990	2,112	44,054	9,591
Michigan	138,575	62,164	24,271	19,694	162,846	81,858
Montana	42,222	13,786	129,987	102,798	172,209	116,584
North Dakota	342,733	172,586	454,849	292,500	797,582	465,086
Oklahoma	90,908	59,337	772	471	91,680	59,808
Texas	254,085	139,090	124,557	103,211	378,642	242,301
Utah	23,571	14,403	254,677	60,790	278,248	75,193
Wyoming	97,153	56,223	74,325	48,874	171,478	105,097
Other(1)	15,251	8,470	2,872	1,695	18,123	10,165
Total	1,114,978	560,779	1,190,687	710,788	2,305,665	1,271,567

(1) Other includes Alabama, Arkansas, Kansas, Mississippi, Nebraska and New Mexico.
(2) Out of a total of approximately 1,190,700 gross (710,800 net) undeveloped acres as of December 31, 2010, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 10% in 2011, 7% in 2012, and 21% in 2013.

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Production History

The following table presents historical information about our produced oil and gas volumes:

	Year Ended December 31,		
	2010	2009	2008
Oil production (MMBbls)	19.0	15.4	12.4
Natural gas production (Bcf)	27.4	29.3	30.4
Total production (MMBOE)	23.6	20.3	17.5
Daily production (MBOE/d)	64.6	55.5	47.9
North Ward Estes field production (1)			
Oil production (MMBbls)	2.7	2.2	1.9
Natural gas production (Bcf)	0.4	0.6	1.2
Total production (MMBOE)	2.8	2.3	2.1
Sanish field production (1)			
Oil production (MMBbls)	6.8	3.7	1.6
Natural gas production (Bcf)	2.5	1.3	0.1
Total production (MMBOE)	7.2	3.9	1.6
Average sales prices:			
Oil (per Bbl)	$70.53	$52.51	$86.99
Natural gas (per Mcf)	$4.86	$3.75	$7.68
Average production costs:			
Production costs (per BOE) (2)	$10.62	$11.10	$12.81

(1) The North Ward Estes and Sanish fields were our only fields that contained 15% or more of our total proved reserve volumes as of December 31, 2010.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $17.7 million ($0.75 per BOE), $12.2 million ($0.61 per BOE), and $16.8 million ($0.96 per BOE) for the years ended December 31, 2010, 2009 and 2008, respectively.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2010. A net well is our percentage ownership of a gross well. Wells in which our interest is limited to royalty and overriding royalty interests are excluded.

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	3,970	1,728	398	132	4,368	1,860
Rocky Mountains	2,341	554	478	264	2,819	818
Mid-Continent	578	368	200	82	778	450
Gulf Coast	96	53	461	117	557	170
Michigan	77	41	1,099	416	1,176	457
Total	7,062	2,744	2,636	1,011	9,698	3,755

(1) 143 wells are multiple completions. These 143 wells contain a total of 352 completions. One or more completions in the same bore hole are counted as one well.

We have an interest in or operate 34 enhanced oil recovery projects, which include both secondary (waterflood) and tertiary (CO_2 injection) recovery efforts, and aggregate production from such enhanced oil recovery fields averaged 17.9 MBOE/d during 2010 or 28% of our 2010 daily production. For these areas, we need to use enhanced recovery techniques in order to maintain oil and gas production from these fields.

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Drilling Activity

We are engaged in numerous drilling activities on properties presently owned and intend to drill or develop other properties acquired in the future. The following table sets forth our drilling activity for the last three years. A dry well is an exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. A productive well is an exploratory, development or extension well that is not a dry well. The information below should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2010:						
Development	163	3	166	73.8	0.7	74.5
Exploratory	20	3	23	10.5	3.0	13.5
Total	183	6	189	84.3	3.7	88.0
2009:						
Development	137	4	141	50.2	2.6	52.8
Exploratory	1	3	4	0.9	2.5	3.4
Total	138	7	145	51.1	5.1	56.2
2008:						
Development	283	20	303	113.3	9.2	122.5
Exploratory	2	3	5	1.9	1.3	3.2
Total	285	23	308	115.2	10.5	125.7

As of December 31, 2010, 22 operated drilling rigs and 43 operated workover rigs were active on our properties. We were also participating in the drilling of two non-operated wells. The breakdown of our operated rigs is as follows:

Region	Drilling	Workover
Rocky Mountain	17	8
Permian	2	3
Mid-Continent/Michigan	-	2
North Ward Estes	-	26
Postle	2	4
Gulf Coast	1	-
Total	22	43

Delivery Commitments

Our production sales agreements contain customary terms and conditions for the oil and natural gas industry, generally provide for sales based on prevailing market prices in the area, and generally have terms of one year or less. We have also entered into physical delivery contracts which require us to deliver fixed volumes of natural gas. As of December 31, 2010, we had delivery commitments of 10.5 Bcf (or 38% of total 2010 natural gas production), 5.7 Bcf (21%) and 4.4 Bcf (16%) for the years ended December 31, 2011, 2012 and 2013, respectively. These contracts were related to production at our Boies Ranch field in Rio Blanco County, Colorado, at our Antrim Shale wells in Michigan and at our Flat Rock field in Uintah County, Utah. We believe our production and reserves are adequate to meet these delivery commitments. See “Quantitative and Qualitative Disclosure about Market Risk” in Item 7A of this Annual Report on Form 10-K for more information about these contracts.

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Item 3. Legal Proceedings

Whiting is subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

In November 2010, Whiting previously disclosed a well incident at the Roggenbuck 14-25H well in North Dakota in which a valve near the well head failed resulting in water, oil and natural gas flowing from the well, with Whiting containing and hauling from the well site the liquids being produced. Whiting received a complaint, dated February 15, 2011, in an administrative action by the North Dakota Industrial Commission alleging that in connection with such incident Whiting violated certain sections of the North Dakota Administrative Code governing the oil and gas industry, including by not controlling subsurface pressure on a well, by allowing oil and brine to flow over and pool on the surface of the land and by not properly maintaining a dike on the well site. The complaint requests that Whiting pay aggregate fines of $162,500 and costs and expenses of $4,357. The incident described above was of relatively short duration, was fully and promptly remediated, and there were no injuries. Whiting intends to investigate the assertions set forth in the complaint and respond as appropriate.

Item 4. Reserved

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2011, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	64	Chairman and Chief Executive Officer
James T. Brown	58	President and Chief Operating Officer
Mark R. Williams	54	Senior Vice President, Exploration and Development
Bruce R. DeBoer	58	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	40	Vice President, Human Resources
Jack R. Ekstrom	64	Vice President, Corporate and Government Relations
J. Douglas Lang	61	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	52	Vice President, Operations
David M. Seery	56	Vice President, Land
Michael J. Stevens	45	Vice President and Chief Financial Officer
Brent P. Jensen	41	Controller and Treasurer

The following biographies describe the business experience of our executive officers:

James J. Volker joined us in August 1983 as Vice President of Corporate Development and served in that position through April 1993. In March 1993, he became a contract consultant to us and served in that capacity until August 2000, at which time he became Executive Vice President and Chief Operating Officer. Mr. Volker was appointed President and Chief Executive Officer and a director in January 2002 and Chairman of the Board in January 2004. Effective January 1, 2011, Mr. Volker stepped down as President, but remains Chairman and Chief Executive Officer. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has 39 years of experience in the oil and gas industry. Mr. Volker has a degree in finance from the University of Denver, an MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager, in January 2000, he became Vice President of Operations, and in May 2007, he became Senior Vice President. Effective January 1, 2011, Mr. Brown was elected President and Chief Operating Officer. Mr. Brown has 36 years of oil and gas experience in the Rocky Mountains, Gulf Coast, California and Alaska. Mr. Brown is a graduate of the University of Wyoming, with a Bachelor's Degree in civil engineering, and the University of Denver, with an MBA.

Mark R. Williams joined us in December 1983 as Exploration Geologist and has been Vice President of Exploration and Development since December 1999. Mr. Williams was elected Senior Vice President, Exploration and Development effective January 1, 2011. He has 30 years of domestic and international experience in the oil and gas industry. Mr. Williams holds a Master's Degree in geology from the Colorado School of Mines and a Bachelor's Degree in geology from the University of Utah.

Bruce R. DeBoer joined us as our Vice President, General Counsel and Corporate Secretary in January 2005. From January 1997 to May 2004, Mr. DeBoer served as Vice President, General Counsel and Corporate Secretary of Tom Brown, Inc., an independent oil and gas exploration and production company. Mr. DeBoer has 31 years of experience in managing the legal departments of several independent oil and gas companies. He holds a Bachelor of Science Degree in Political Science from South Dakota State University and received his J.D. and MBA degrees from the University of South Dakota.

Heather M. Duncan joined us in February 2002 as Assistant Director of Human Resources and in January 2003 became Director of Human Resources. In January 2008, she was appointed Vice President of Human Resources. Ms. Duncan has 14 years of human resources experience in the oil and gas industry. She holds a Bachelor of Arts Degree in Anthropology and an MBA from the University of Colorado. She is a certified Senior Professional in Human Resources.

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Jack R. Ekstrom joined us in September 2008 as Executive Director, Corporate Communications and Investor Relations, and became Vice President, Corporate and Government Relations in January 2010. From 2004 to 2008, Mr. Ekstrom served as the Director of Government Affairs for Pioneer Natural Resources, an independent oil and gas exploration and production company. Prior to this he served as the Director of Government Affairs for Evergreen Resources and Forest Oil. He has 36 years of experience in the oil and gas industry. Mr. Ekstrom is a Director of the Colorado Oil & Gas Association and the Western Energy Alliance, and is a past chairman of the Western Business Roundtable and past president of the Denver Petroleum Club. He holds a Bachelor of Arts Degree in Communications from Augustana College in Rock Island, Illinois.

J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager of Acquisitions and Reservoir Engineering in January 2004 and Vice President, Reservoir Engineering and Acquisitions in October 2004. His 37 years of acquisition and reservoir engineering experience has included staff and managerial positions with Amoco, Petro-Lewis, General Atlantic Resources, UMC Petroleum and Ocean Energy. Mr. Lang holds a Bachelor's Degree in Petroleum Engineering from the University of Wyoming and an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

Rick A. Ross joined us in March 1999 as an Operations Manager. In May 2007, he became Vice President of Operations. Mr. Ross has 28 years of oil and gas experience, including 17 years with Amoco Production Company where he served in various technical and managerial positions. Mr. Ross holds a Bachelor of Science Degree in Mechanical Engineering from the South Dakota School of Mines and Technology. He is a registered Professional Engineer and is currently Chairman of the North Dakota Petroleum Council.

David M. Seery joined us as our Manager of Land in July 2004 as a result of our acquisition of Equity Oil Company, where he was Manager of Land and Manager of Equity's Exploration Department, positions he had held for more than five years. He became our Vice President of Land in January 2005. Mr. Seery has 30 years of land experience including staff and managerial positions with Marathon Oil Company. Mr. Seery holds a Bachelor of Science Degree in Business Administration from the University of Montana.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002 and became Vice President and Chief Financial Officer in March 2005. His 24 years of oil and gas experience includes eight years of service in various positions including Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and gas exploration and development. He spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is a graduate of Mankato State University of Minnesota and is a Certified Public Accountant.

Brent P. Jensen joined us in August 2005 as Controller, and he became Controller and Treasurer in January 2006. He was previously with PricewaterhouseCoopers L.L.P. in Houston, Texas, where he held various positions in their oil and gas audit practice since 1994, which included assignments of four years in Moscow, Russia and three years in Milan, Italy. He has 17 years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree from the University of California, Los Angeles.

Executive officers are elected by, and serve at the discretion of, the Board of Directors. There are no family relationships between any of our directors or executive officers.

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PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Whiting Petroleum Corporation's common stock is traded on the New York Stock Exchange under the symbol "WLL". The following table shows the high and low sale prices for our common stock (as adjusted for the two-for-one stock split as noted below) for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2010		
Fourth Quarter (Ended December 31, 2010)	$59.40	$47.95
Third Quarter (Ended September 30, 2010)	$49.14	$36.82
Second Quarter (Ended June 30, 2010)	$46.61	$35.61
First Quarter (Ended March 31, 2010)	$40.88	$31.33
Fiscal Year Ended December 31, 2009		
Fourth Quarter (Ended December 31, 2009)	$37.83	$26.34
Third Quarter (Ended September 30, 2009)	$29.71	$14.89
Second Quarter (Ended June 30, 2009)	$24.97	$12.27
First Quarter (Ended March 31, 2009)	$22.50	$9.63

On January 26, 2011, our Board of Directors approved a two-for-one split of the Company's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. All share and per share amounts in this Annual Report on Form 10-K have been retroactively adjusted to reflect the stock split for all periods presented.

On February 22, 2011, there were 747 holders of record of our common stock.

We have not paid any dividends on our common stock since we were incorporated in July 2003, and we do not anticipate paying any such dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our financial position, cash flows, results of operations, capital requirements and investment opportunities. Except for limited exceptions, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, our credit agreement restricts our ability to make any dividends or distributions on our common stock. Additionally, the indentures governing our senior subordinated notes contain restrictive covenants that may limit our ability to pay cash dividends on our common stock and our 6.25% convertible perpetual preferred stock.

Information relating to compensation plans under which our equity securities are authorized for issuance is set forth in Part III, Item 12 of this Annual Report on Form 10-K.

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares on a cumulative basis changes since December 31, 2005 in (a) the total stockholder return on our common stock with (b) the total return on the Standard & Poor's Composite 500 Index and (c) the total return on the Dow Jones US Oil Companies, Secondary Index. Such changes have been measured by dividing (a) the sum of (i) the amount of dividends for the measurement period, assuming dividend reinvestment, and (ii) the difference between the price per share at the end of and the beginning of the measurement period, by (b) the price per share at the beginning of the measurement period. The graph assumes $100 was invested on December 31, 2005 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

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	12/31/05	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
Whiting Petroleum Corporation	$ 100	$ 117	$ 144	$ 84	$ 179	$ 293
Standard & Poor’s Composite 500 Index	$ 100	$ 114	$ 118	$ 72	$ 89	$ 101
Dow Jones US Oil Companies, Secondary Index	$ 100	$ 105	$ 149	$ 89	$ 123	$ 143

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Item 6. Selected Financial Data

The consolidated statements of income and statements of cash flows information for the years ended December 31, 2010, 2009 and 2008 and the consolidated balance sheet information at December 31, 2010 and 2009 are derived from our audited financial statements included elsewhere in this report. The consolidated statements of income and statements of cash flows information for the years ended December 31, 2007 and 2006 and the consolidated balance sheet information at December 31, 2008, 2007 and 2006 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent acquisitions beginning on the following dates: Redtail Prospect, September 1, 2010; Additional interests in North Ward Estes, November 1, 2009 and October 1, 2009; Flat Rock Natural Gas Field, May 30, 2008; and Michigan Properties, August 15, 2006.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(dollars in millions, except per share data)				